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Modelling renewable energy impact on the electricity market in India

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ABSTRACT

Renewable power generation development, most notably for wind and solar, has taken off at a rapid pace in India especially in the last 4 years. While these developments have many positive aspects, a rapid shift in balance of baseload and intermittent generation must be assessed carefully to ensure the share of renewable power generation increases without compromising system security and economics. Seasonal and spatial variability of wind, and to a lesser extent that of solar, can render these resources to have low availability for a significant part of the year leading to an increase in unserved energy, i.e., deteriorate system reliability. The intermittency of generation also impacts on inter-state power flows and lead to higher congestion in the grid. Climate model results provide a rich set of information on the nature of solar/wind variability that can be embedded in an electricity market simulation tool to assess these impacts on prices, generation dispatch and power flows. We have developed a modelling analysis for the Indian national electricity market informed by CSIRO climate model results. We have assessed the added costs arising from intermittency to put in perspective the true costs and benefits of renewable power. We have focused on the near-term developments in 2017 to show how some of the high renewable growth scenarios included in the Indian National Electricity Plan may imply significant pressure on inter-state/region transfer capability, and lead to a significant worsening of system reliability. The outcome of our modelling analysis suggests that a more orderly and balanced development of renewable and conventional power generation capacity is needed with a stronger focus on system economics and security.

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Table 1
Installed renewable capacity and short/medium/long term target (MW).

	Total installed capacity (MW)	Targeted for next year (2012/13)	Target for next five years (2017)	Target for next decade (2022)	Long term potential
Wind	18,192	2500	11,000–15,000	50,000	Wide range: 48,000 [4] to $>$2,000,000 [5]
Solar	1045	800	4000–10,000	20,000	200,000 (by 2050) [6]
Other	6806	805	3000–5000	15,000	88,000 [6]

1. Introduction

1.1. Electricity market in India

The electricity market in India catered for 123 Giga Watt (GW) of peak demand and 911 Terra Watt hour (TWh) energy in 2012/13. The generation capacity in India is 225 GW including 153 GW (or 68 per cent, including 132 GW of coal) thermal, 39.6 GW of hydro, 27.5 GW of other renewables and 4.8 GW of nuclear [1]. Despite a significant growth in capacity over the years, especially that of wind and solar in recent years, supply has perpetually lagged behind demand. As a result, in 2012/13 financial year, the country still faced a peak and energy shortage of 9 and 8.7 per cent, respectively. A move towards competitive electricity markets began in the nineties when the peak/energy shortages were in fact far greater. A number of regulatory developments starting with the Electricity Act in 2003 facilitated the di-licensing generation to allow multiple buyers and sellers in the market, followed by the Open Access Regulation in 2008 that formed the backbone of electricity markets.

Since 2008, there are two Power Exchanges in India, namely, the Indian Energy Exchange (IEX) and the Power Exchange India Limited (PXIL), that operate a range of intra-day, daily and weekly markets. The electricity market in India is, however, primarily structured around long-term Power Purchase Agreements (PPA) that account for 90 per cent of the 876 TWh electricity bought and sold in 2011/12. The volume of trade through the Power Exchanges is still relatively small at around 24 TWh year^{-1} in 2012/13. i.e., only 2.8 per cent of the total energy requirements. However, the volume of trade in the short-term market has grown significantly 7 TWh in 2009/10 and the number of participants in IEX, which has 97 per cent of the market share, has grown from 175 in 2009 to over 2000 in 2013 [2]. Trading of Renewable Energy Certificates (REC) commenced via Power Exchanges in February 2011. IEX also holds the major market share of 77 per cent for the REC market and has posted a trading volume of 2.9 million renewable MWh.

Power Exchanges operate a Day Ahead Market (DAM) on a 15-min basis and a Term Ahead Market (TAM) for daily/weekly trading. Spot prices are set in the market clearing prices for 12 market zones across the country covering the five sub-regions in India (namely, North, West, South, East and North-East). There are effectively two separate grids in India namely North-East-West (N.E.W.) Grid and the South Grid. These two grids are interconnected asynchronously through HVDC links. Spot prices in recent years have exhibited significant temporal and spatial volatility that serves an important purpose of indicating the need for new investments. Although the Power Exchanges serve a small part of the energy, an efficient and transparent price discovery process has already been a major aid in pricing long term contracts and signalling the location and type of capacity needed in the market.

1.2. Renewable energy in India: present status and future targets

Grid-connected renewable power generation in India has seen a spectacular growth in recent years – most notably since the beginning of 2010. Starting with a very low base of renewables in 2000, the installed capacity of grid-connected renewables has reached 27.5 GW in June 2013 – more than 33 per cent of it has come about in last five years and over 7 GW of this is in the form of wind in the Southern state of Tamil Nadu. The major impetus of this development comes from the National Action Plan on Climate Change that promises to deliver 15 per cent of the total electricity energy from renewables by 2020. Table 1 shows the composition of grid-connected installed capacity of renewable generators, along with the short/medium term target and the estimated long term resource potential. Wind dominates the share of renewable at present, although solar power is also adding to the mix of renewables at a faster rate driven mostly by the 20 GW National Solar Mission. A state-based Renewable Purchase Obligation (RPO) is the cornerstone of the renewable policy in India that sets the target by geography and year for each state, determined by the respective state commission. In addition, there are federal/national targets that are overlaid to include a separate solar energy target [3]. The National Solar Mission i.e., the 20 GW solar target, is applied uniformly across all states – there is no differentiation in solar tariff across the states. Most states currently have a solar target of 0.25 per cent of total energy that is expected to rise to 3 per cent by 2020 in line with the national target.

The absolute dominance of wind and solar over other forms of renewable resources is evident from the medium term target (over the next 10 years), and also the long term potentials that are available from different sources. It is estimated that that over the next two 5-year plans, a total wind capacity addition of $\sim$50 GW will be achieved. A significant part of the future wind capacity addition is being planned in the Southern Indian state of Tamil Nadu. There is however significant confusion on the long term potential of wind. The original estimate from the Ministry of Power/C-WET [4] had estimated it around 48 GW, but a more recent study by Phadke et al. [5] has estimated a wind potential in excess of 2000 GW, i.e., a 42-fold increase in the original estimate. The solar power potential reported in Central Electricity Authority's National Electricity Plan (NEP) for 2050 is projected to be 200 GW [6]. The long term potential of all other renewable resources including biomass is likely to grow from 6.8 GW in 2012 to just over 15 GW over the next decade, i.e., an addition of $\sim$8 GW, in comparison to 19 GW of solar and over 30 GW of wind.

The capital cost for adding renewable especially solar is significant. It has been estimated that the National Solar Mission would cost around INR 3 trillion or USD 60 billion [6] covering all three phases up to 2020.

1.2.1. High renewable target, variability of wind/solar and their ramifications

Addition of renewable to the coal-dominated generation system in India is clearly a welcome development to boost production, especially during periods of constrained coal supply [7]. Indeed, it helps to contain carbon emissions. Apart from these two benefits, it has a number of other ancillary benefits to scale up the renewable industry and bring down the cost of production of solar panels and wind turbines. However, it is also important to keep in mind the cost and power system impact of these resources,

especially in light of the massive capacity addition targets that are being drafted in the NEP. An exploration of climate model results for the Indian sub-continent that we have undertaken in our previous study [3] shows three key issues that call into question the efficacy of a very high intermittent renewable share, namely:

1. *Seasonal variability*: Both solar and wind have significant seasonal variability. The seasonal trend of wind in particular is very strong with very low availability during pre-monsoon (April/May) and post-monsoon (September/October) months in India. More importantly, (high) wind availability more or less coincides with that of hydro during June–July, i.e., they do not necessarily complement each other, except for the fact that a small part of the hydro capacity has storage capability that effectively allows part of the hydro energy to be stored during off-peak hours/days and weeks/months and utilise them during peak hours/days/weeks. In fact, all three renewable resources have some degree of correlation with their availability being generally high during June–August and falling off rapidly during the winter months, albeit the correlation between solar and wind can vary considerably across regions. The seasonal variability raises two critical issues:
   a. In the short term, a peak/energy deficit system would exhibit high volatility of prices in the wholesale electricity market as wind/solar power fluctuate over the months.
   b. In the longer term, it also means there needs to be backup conventional coal/gas/oil fired capacity to supplant for these resources for a significant part of the year. Since majority of the Indian states are peak/energy deficient, the seasonal variability severely dents the relative economics of wind in particular, compared to conventional generation capacity. The "firm capacity" of intermittent generation has been estimated to be in the range of 10–30 per cent of installed capacity (e.g., [8,9]). Put differently, every MW of wind, and to some extent solar, would need somewhere between 0.7 and 0.9 MW of back-up peaking capacity, failing which the system is exposed to significant risk of outage, particularly during the pre/post-monsoon months.
2. *Limited locations:* Contrary to a popular belief, our analysis of climate data in [3] suggests there are limited locations in India where good quality solar and wind resources are available. Balaji et al. [10] also reconfirms the limited number of wind sites. It therefore reopens some of the confusions that have shown up in vastly differing wind energy potential that ranges from less than 50 GW which is the official estimate and in excess of 2000 GW according to Phadke et al. [5]. Apart from the feasibility of the high end estimate of wind energy potential, it also raises an economic issue. As majority of the high-quality resource sites mostly in coastal areas are exploited, it would effectively lower capacity factor of wind generation, which in turn would raise the delivered cost of electricity – further diminishing the attractiveness of wind/solar.
3. *Intra-day variability:* The variability within a day can also be significant that has major ramifications for system security and requires significant strengthening of the transmission network and enhancing ancillary services, i.e., different classes of reserve that must be held by generators to counter rapid decrease and increase of wind/solar.

In fact, the high concentration of wind in Tamil Nadu has arguably already started showing some of the short term symptoms:

- Fig. 1 shows how electricity spot prices (from IEX) in South India, which has the higher concentration of wind power, have peaked during April/May over the last 3 years when wind generation is typically very low. Monthly average prices for pre-monsoon months clearly show a rising trend of high prices that is more than double of prices in the other three zones. High degree of intermittent generation is *one* of the factors that puts pressure on inter-regional transmission, leading to significant periods of price separation among the major zones.
  This price increase may appear confusing because renewable power has generally been associated with a *drop* in spot prices. Indeed, intermittent solar/wind generation during periods of high availability can cause spot prices to drop significantly as has been observed by Sensfuß et al. [11] for Germany and [12] for Australia – an effect that is also observed in India as discussed below (and also in the modelling analysis section towards the end). However, as wind/solar generation drops away significantly during part of the year/season/month/day, there is significant stress exerted on the generation and transmission system that is reflected in an *increase* in price, if not a significant jump in spot price. This is particularly true in capacity-deficient system like India that simply cannot cope with the vast gap in demand and supply during periods of low wind/solar availability. This is particularly true if these resources have come at the expense of baseload coal/gas capacity leaving the system highly deficient in baseload capacity. Intermittency of solar/wind can cause price volatility even in capacity-surplus systems in developed nations as some of the most expensive generation bids may set the price for such periods [13]. However, in a capacity-deficient system, the effect would be far more pronounced with sustained hours of load shedding as spot prices hit the price cap, which is precisely what pre-monsoon month prices in Southern India (in Fig. 1) exhibit.
- There are other factors such as an increase in coal prices, reduction in coal availability and problems with nuclear capacity development, etc. that may have also contributed to higher (pre-monsoon) prices. Since wholesale electricity prices in real-time reflect an array of factors, it is quite impossible to attribute the addition of wind/renewable *alone* to a specific price outcome. This is not the central tenet of the paper in any case. Nevertheless, high volume of wind in Southern India has at least partly contributed to seasonally volatile prices even if we take into account the general lack of capacity/energy arising from these other factors. We note that (a) these other factors are broadly applicable to all regions and not specific to Southern India; (b) the price impacts arising from a chronic supply capacity shortage is unlikely to be seasonal in Southern India which has a lower share of hydro generation (14 per cent over

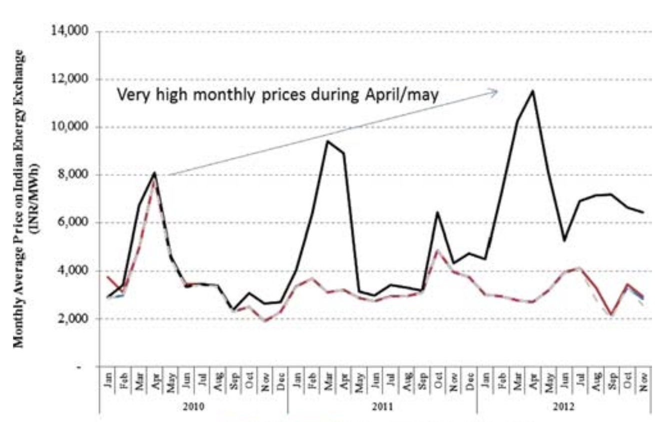


Fig. 1. Electricity prices on Indian Energy Exchange for four major regions: 2010–2012 *Note:* Data obtained from Indian Energy Exchange (IEX) website. In November, 2012, 1 USD = approx. INR 55.

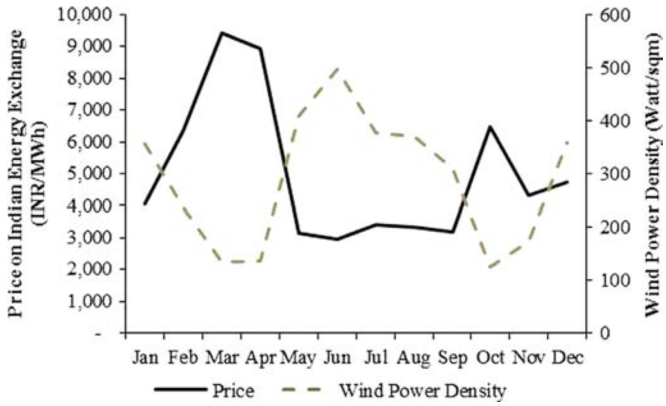


Fig. 2. Electricity prices (monthly averages in 2011) and average wind power density: Southern India. *Note:* Wind Power Density is obtained as climate model reanalysis data for 1980–2000.

2010–2012) compared to Northern India (26 per cent over 2010–2012); and (c) we have largely controlled for these other factors in our modelling analysis that we have discussed in a later part of this paper. Our analysis shows that even if we assume relatively low (historic) coal prices and planned baseload capacity addition goes ahead in all regions, increasing intermittent generation can cause significant seasonal variability in prices in Southern India.

- In order to foreshadow some of the modelling analysis that we have presented in the subsequent sections and to provide further insights into the seasonal price volatility, we have used climate model reanalysis data to first show how price variations closely reflect availability of wind. Fig. 2 shows wind power density for the Southern region dropping off significantly during months when IEX spot prices precisely rose to a very high level. An alarming sign is that the Apr/May price peak has grown over the last 3 years as we have witnessed addition of over 3000 MW of wind capacity in Tamil Nadu (South Indian state) alone over this period. We have undertaken a modelling analysis for Tamil Nadu [14], for 2017 to demonstrate how the current plan to add further intermittent resources can render the state's power system progressively even less reliable and incur much higher costs/prices.

As the discussion above alludes to, power system planning is far more complex than simply building plenty of renewables. Apart from the technical issues that we have raised above, renewable projects can also cause a debt crunch for other power projects. Capital costs of renewable projects (on an equivalent MW basis) in most cases are higher than that of conventional coal and gas based projects. In reality, the power sector in any country competes for investment with other sectors. The NEP [6] states that INR 1.4 trillion, or 38 per cent, out of a total INR 3.7 trillion capital requirement over 2013–2017 has been earmarked for funding the Second Phase (2013–2017) of the 20,000 MW National Solar Mission[1]. As funds are used to renewable projects, often through attractive feed-in tariff and other financial incentives, there would in fact be less capital available for conventional gas/coal/hydro projects. If we consider the recent history of baseload power projects in India, there has been very limited addition of it in places like Tamil Nadu for more than a decade now. While there are other formidable constraints that can be attributed to such lack of development, not the least of which is a constraint on coal, one has to recognise that diversion of funds in the form of government and private sector equity and debt capital to renewable projects has also contributed to this.

[1] Tables 4.11 (p.70) and 9.12 (p.167) of National Electricity Plan (Generation) [6].

1.2.2. Scope of this work

As the discussion above alludes to – introduction of very high volume of renewable is not necessarily an unmixed blessing, especially in a peak/energy deficit system. It needs to be managed carefully using a scientific approach informed by climate modelling analysis. We have first summarised a climate dataset for the Indian region that comprehensively captures the spatial and temporal variability of wind and solar resources. While there is significant progress in renewable power production development, there has been little analysis to date to fully understand the dispatch/pricing implication of the variability of these resources and, in particular, how the prices in electricity market and the congestion in the physical transmission system react to a high volume of intermittent resources. The implications for a peak/energy deficit system are particularly grave, especially if addition of renewable power compromises the ability to add conventional generation capacity. There are economic and security issues that need to be considered to weigh up the benefits of renewables with the real cost that these resources impose on the system. Unfortunately, the power system planning approach in the NEP [6] does not analyse this trade-off well. To be precise, in the NEP, these projects are given a special "must-run" status, i.e., are automatically selected. As NEP [p.96] notes the renewable projects "*were accorded priority and taken as must run projects on account of their inherent advantages*". Since the power system and market are already showing symptoms of stress arising from intermittent generation, a rapid expansion of this capacity should be examined more closely.

We have undertaken an electricity market modelling analysis to analyse the following two NEP medium-term scenarios for 2017:

- A Base Case or "Low Renewable" (**LOW_RENEW**) scenario that assumes 18,500 MW of additional renewable capacity including 11,000 MW of wind and 4000 MW of solar; and
- A "High Renewable" (**HIGH_RENEW**) scenario that assumed 30,000 MW of renewables including 15,000 MW of wind and 10,000 MW of solar. This scenario has 6000 MW less conventional baseload capacity, but still has 5500 MW higher overall installed capacity compared to LOW_RENEW.

2. Climate data

2.1. Climate data employed

We have first used the climate data from the European Centre for Medium-Range Weather Forecasts (ECMWF) ERA-Interim reanalysis database ("**ERA data**") at a horizontal resolution of $1.5^\circ \times 1.5^\circ$ [15]. ERA-Interim is the latest reanalysis product from ECMWF which has made considerable improvements against the earlier product ERA-40. Dee et al. [15] provides a detailed description of the various observational products used as well as the four dimensional data assimilation technique, and the forecast model used in creating the reanalysis data. We have used the ERA-Interim data from January 1980 to December 2010 to calculate annual and monthly mean of downward solar radiation, and 10 m (and 40 m) wind speed. The specifications of the data used are given below:

- *Downward solar radiation* (*SSRD*): 12 h forecast data for 0 UTC analysis period. We have converted this data to equivalent annual energy intensity and daily average intensity.

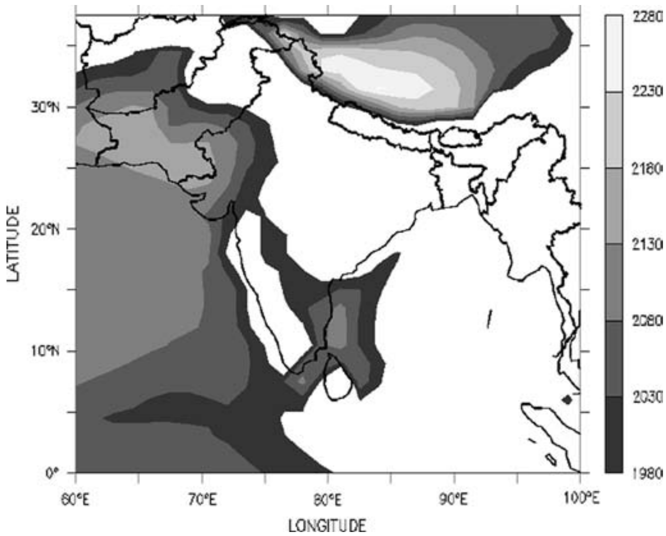


Fig. 3. Annual Average Solar insolation > 0.2000 kWh/sqm/day (1980–2010).

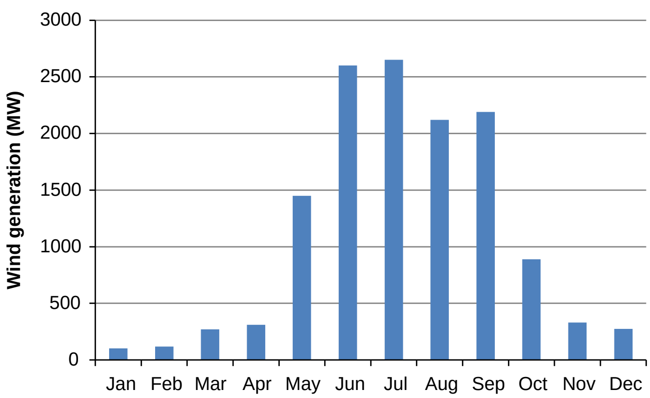


Fig. 4. Actual wind generation in Southern India (evening peak).
Source: Compiled from Regional Load Despatch Centre Data for 2011.

- 10 m *and* 40 m *wind speed*: monthly mean of daily mean 10 m wind speed We have calculated the wind power density at 10/40 m assuming a Rayleigh distribution of wind speed and air density of 1.23 kg/m^3.

We recognise that the resolution of the data is coarse. Nevertheless, it is adequate for our purpose to show broad trends of resource distribution. We have also checked that using a better (0.75° × 0.75°) resolution yields very similar outcomes.

Fig. 3 shows solar insolation data for areas that exceed approximately 2000 kWh/sqm/year. Since the commercial viability of large-scale solar PV installations drop considerably below an annual solar radiation of 2000, we have included areas that have solar radiation of 1980 or higher. It is immediately obvious that good quality solar resources that are commercially viable in the near-term are confined to a relatively small part of the country – mostly in Western/North-Western and South-East India.

We have shown in [3] how the wind resources are located mostly around the coast line and few other parts of Southern India. It has also been echoed in many other forums and publications including [10]. The geographical distribution of these resources across the states and the seasonal variability within each state also presents a major challenge to the power system operator. Fig. 4 below illustrates the variability issue using *actual* wind generation (in 2011) in Southern India that accounts for approximately 60 per cent of total wind capacity in the country. For nearly 6 months in a year, wind capacity contributes very little during the evening peak period when capacity falls well short of demand. The monsoon period during which wind generation peaks, coincides with hydro peak, leaving excess generation, especially during off-peak which also poses some problems to manage excess off-peak baseload capacity. It may be worth noting that 52 per cent of the installed hydro capacity in the Southern region is run-of-the-river type with practically no storage capability and only 2879 MW of capacity (or approximately 25 per cent of total installed hydro capacity) has longer term storage of more than 4 weeks [16]. It is therefore unlikely that storage hydro can contribute in any significant way to manage the variability in the region that already has intermittent generation capacity of over 12 GW that exceeds the total hydro capacity (11 GW), and far in excess of long term storage hydro.

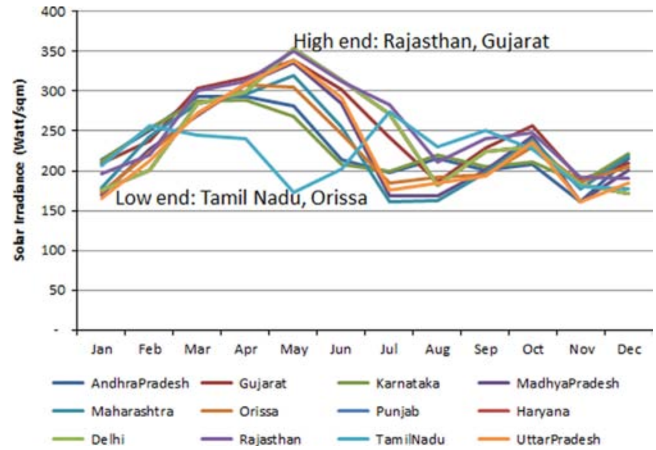


Fig. 5. Geographical and seasonal variation of solar irradiance. *Note*: Compiled from CSIRO Climate Model Output for 1980. We have shown only those states that have a daily solar irradiance of at least 5 kWh/sqm.

An examination of climate model results provides significant insights into the nature of variability for the entire country. Fig. 5 shows geographical and seasonal variability in solar irradiance results from CSIRO's Conformal Cubic Atmospheric Model (CCAM) [17] for a single year. CCAM is run at a uniform 60 km horizontal resolution with bias corrected sea surface temperature to produce present-day climate simulations. Seasonal variation in all states is significant especially during the transition from winter (Dec/Jan) to pre-monsoon period (Apr/May). However, as the figure amply demonstrates, the geographical spread is also very significant.

This geographic and temporal variability poses a problem considering that the generation capacity is often inadequate to meet peak demand even when all of the resources are available. As Fig. 6 shows, the variability of wind (for year 1980) is significantly more prominent. The peak wind months in wind resource-rich states like Tamil Nadu (in South) and Gujarat (in West) are strongly correlated, which means during the monsoon period, all of these states will probably end up with surplus wind generation especially during night hours, whereas pre-monsoon and winter months will still face peak power shortage.

We now turn our attention to the unpredictable nature of these resources. We have used CCAM simulations for 21 years (1980–2000) to show the inter-annual variability of solar and wind. As Fig. 7 shows, even in the most solar resource-rich state of Rajasthan in Western India, there is some degree of uncertainty of availability of resource at least for part of the year (e.g., Jun–Oct). According to this 21-year model dataset, energy outputs may vary up to 20 per cent- a significant variation that may account for up to 4000 MW of peaking capacity in a perennially peak-deficit system if the 20 GW National Solar Mission is achieved.

The degree of uncertainty for wind is much higher. Fig. 8 best explains the degree of variability for both wind and solar. We have shown the cumulative distribution of wind and solar power

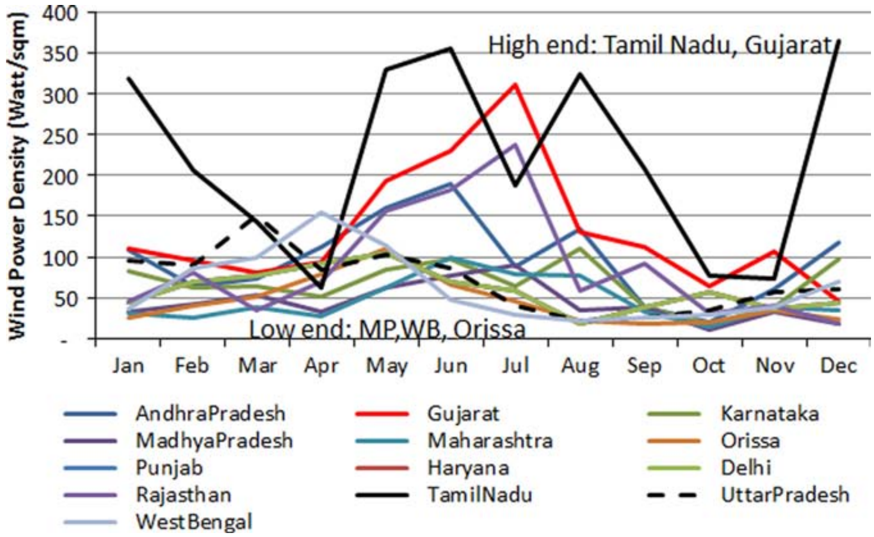


Fig. 6. Geographical and seasonal variability in wind. Note: WB: West Bengal, MP: Madhya Pradesh.
Source: Compiled from CSIRO Climate Model output.

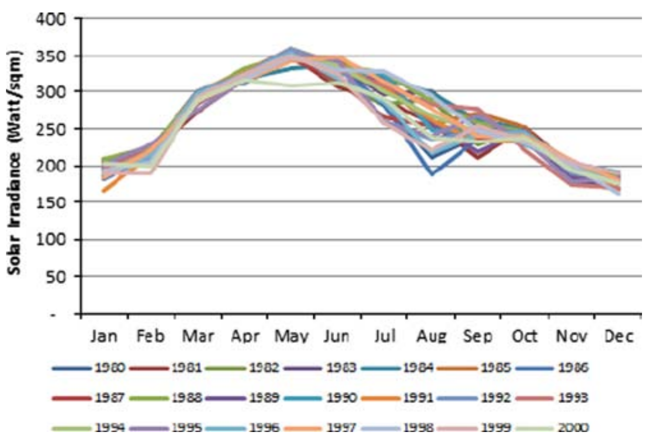


Fig. 7. Uncertainty of solar irradiance: inter-annual variability for Rajasthan.
Source: Compiled from CSIRO Climate Model Output.

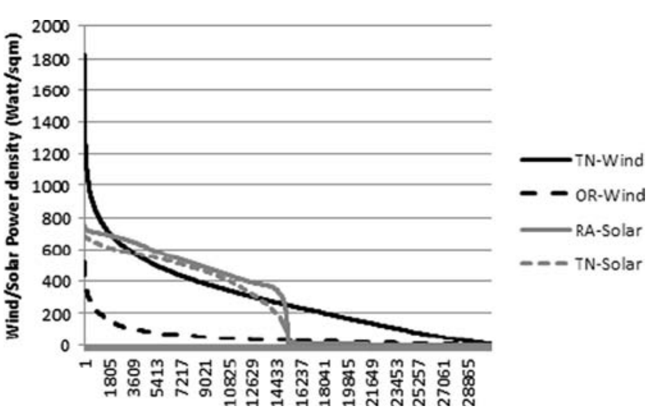


Fig. 8. Cumulative distribution of high and low ends of solar and wind. Note: (a) 21 year, 6-hourly model output used to obtain the cumulative distribution. (b) RA: Rajasthan, TN: Tamil Nadu, OR: Orissa.
Source: Compiled from CSIRO Climate Model output from 21 years of model simulation.

density for the high as well as the low end for these two resources. The distribution is created using 6-hourly block data (i.e., each day is divided into 4 time blocks) over a 21 year period (i.e., 4 blocks $\times$ 365 days $\times$ 21 years, or 30,660 data points). It represents the composite variability in these resources for each state, which is clearly very significant for wind in particular. We have used the state-specific seasonal probability distribution of wind and solar similar to those shown in Fig. 8 for the modelling analysis discussed next.

3. Implications of variability: modelling analysis

There is limited transmission capacity along some of the key inter-state corridors in India that has already exposed the system to major grid disturbances [18]. The implication of intermittency in terms of high reserve requirements in the system [19] and related technical and regulatory issues [20] are being researched extensively in many countries [21]. Although this is a relatively recent topic, there is already a significant volume of academic and industry literature on this issue that highlights the challenges that power systems including capacity-surplus systems are facing. Given our specific focus on climate data analysis in the Indian context, we have not reviewed the full literature. It would suffice to say that a high penetration of wind/solar may mean the system may be even more vulnerable going forward because it simply cannot cope with a major swing in wind/solar generation [19,21]. The upshot is also a direct impact on market prices as major surge of wind/solar comes on the system to depress prices, or worse disappears leading to very high prices often accompanied by load shed events. As we demonstrate in a later part of this paper, this pattern is likely to get stronger over the years if renewable penetration increases without commensurate increase in firm capacity.

3.1. Modelling framework

Our analysis covers the entire Indian power system in 2017 using a Monte Carlo based Direct Current Approximation of Optimal Power Flow (DC-OP)F model that captures the flows among the state nodes (most of which also happen to be zones in the power market). The model reflects market clearing optimisation of energy and reserve used in advanced electricity markets in Australia/New Zealand. The modelling framework integrates investment optimisation that has been used for climate change policy analysis in Australia [22], Monte Carlo simulation to

represent uncertainties on renewable resource uncertainty [23], and an LP-based operational transmission-constrained dispatch optimisation originally developed for the Indian power system in the nineties [24]. The model we have used contains over 700 generating units and 165 inter-state/regional interconnectors in the Indian power system. We have set the model up with monthly load duration curves to capture both seasonal trends in prices and peak/off-peak variation in dispatch and prices within each month.

The enhancements to the model, i.e., over and above the components in [22–24], include a better representation of renewable resource uncertainty. The model incorporates "contingencies" associated with a surge/drop in intermittent solar/wind generation constructed using climate model data that we have discussed in the preceding section. In this section, we have briefly discussed the salient aspects of the model including the objective function, transmission constraints and finally the enhanced reserve/contingency constraints.

3.1.1. Objective function

The objective function represents the cost, to the system as a whole, of generation offer (*Gen*)/fuel and reserve offer (*Reserve*) costs. They are calculated as the product of the offer/fuel price/cost and the generation/reserve MW amounts cleared. In addition, violation penalties on the various constraints (*Unmet or Excess*) also appear in the objective function.

The *NetCost* is minimised, where the undiscounted net cost for year y is defined as

$$\begin{aligned}
NetCost_y = & \sum_{g,t,go} GenO_{g,y,t,go} \times \text{Duration}_t \times \text{GenCost}_{g,y,t,go} \\
& + \sum_{t,g,rc,ro} \text{Duration}_t \times \text{ResCost}_{g,rc,ro} \times Reserve_{g,rc,ro,y,t} \\
& + \sum_{ng} \text{CapCost}_{ng,y} \times Cap_{ng,y} + \sum_{g} \text{FixedOM}_{g,y} \times Cap_{g,y} \\
& + \sum_{g} \text{VarOM}_{g,y} \times Gen_{g,f,t,y} \times \text{Duration}_t \\
& + \sum_{r,t} \text{VoLL} \times \text{Duration}_t \times Unmet\ Dem_{r,y,t} \\
& + \sum_{r,t} \text{ResVoLL} \times \text{Duration}_t \times Unmet\ Res_{r,y,t} \\
& + \sum_{g} \text{AnnualEnergyVoLL} \times Deficit\ Annual\ Energy_{g,y} \\
& + \sum_{\{t,rc\}} \text{Duration}_t \times \text{RiskVoll} \times Deficit\ Risk_{rc,y,t}
\end{aligned}$$

where g is the Generators (existing and new), eg are existing generators and ng are new generators, go the generation offers (or short run marginal costs of generation) from g, y is the Planning years, $r,r1$ is the Regions/zones, t is the Time blocks of load duration curve. Each block has a pre-specified duration (Duration), rc is the Classes of spinning reserve, ro is the reserve offers (or short run marginal cost of reserve provision) and f the fuel type.

Sum of all cleared generation offers (*GenO*) determines the total generation from g. GenCost and ResCost represent short run marginal cost for generation and reserve for offer tranch go and ro, respectively. We assumed zero reserve costs for the present study. Apart from offer costs, generators also have variable (*VarOM*) and fixed (*FixedOM*) operation and maintenance costs. The objective function also includes capacity investment (MW) decisions *Cap* multiplied by *Capcost* which is the annualised capital cost ($/MW/year) associated with such investments. In addition to regular investment and operational costs, the objective function includes penalties associated with violation of demand constraint (VoLL which is set at USD 500 MWh^{-1} for this study), reserve limit (ResVoLL which is set at the annualised cost of a peaking station), annual energy limit for hydro generators (AnnualEnergyVoLL, set at half of VoLL) and violation of risk constraint (RiskVoLL). VoLL sets the marginal cost of supply at a node (or, nodal spot price in an electricity market), whenever demand at the node exceeds available supply (MW) including imports. Measures of marginal cost of supply/price and the underlying volatility of it arising in part from variability in intermittent generation would be directly influenced by the VoLL. As we have alluded to before, we have used a relatively low estimate of VoLL by international standard, which has the implication of understating the volatility.

The discounted net benefit for the whole planning period is calculated as Z, the objective function to be minimised,

$$Z = \Sigma \text{Delta}_y \times NetCost_y$$

GenCost and CapCost are (optional) random parameters in the model for situations where there is great uncertainty on fuel and/or capital costs and a reasonable approximation of the distribution of these costs is available.

3.1.2. Transmission constraints

The model captures transmission flows across the state nodes in India, derived from a highly detailed load flow model of the Indian national grid for 2016/17. As we have discussed in the next section, the transmission capacity, or flow limits, fully reflect all of the transmission capacity upgrades that have been planned between 2013 and 2017. The inter-state flow equations are those of a DC power flow model, in which the flow of power (MW) between two nodes (r and $r1$) is given by the susceptance of the transmission line, denoted by parameter $X_{r,r1,l}$ and the difference in the voltage angles at the ends of the line, denoted by $Angle_{r,y,t}$. The $Angle_{r,y,t}$ variables are internal variables only, although if necessary, they could be constrained by angular security constraints for stability reasons. The flow in each line has a notional positive direction.

Flow is implicitly constrained to lie between the flows specified for the most extreme points used in the loss representation. The line may also be constrained to lie within bounds, which may represent the thermal flow limits of the line and its associated terminal equipment, but are more usually determined by consideration of contingency situations arising from line outages. The forward limit is always positive, and the backward limit negative.

$$\begin{aligned}
Tran_{r,r1,y,t} &\geq \text{Max Reverse}_{r,r1,y} \quad \{\forall r, r1, y, t | (r, r1) \in K\} \\
Tran_{r,r1,y,t} &\leq \text{Max Forward}_{r,r1,y} \quad \{\forall r, r1, y, t | (r, r1) \in K\}
\end{aligned}$$

Note that the $\text{MaxReverse}_{r,r1}$ and $\text{MaxForward}_{r,r1}$ may be restricted due to estimated reactive power flows on the line. Notionally, the line flow is the flow at the "midpoint" of the line (since half of the losses are allocated to each end), so that the limits imposed also relate to a notional flow limit at the midpoint of the line, and need to be set accordingly.

$$\left.\begin{aligned}
Tran_{r,r1,y,t} &= (Angle_{r,y,t} - Angle_{r1,y,t})/X_{r,r1,y} \\
Angle_{\text{REFERENCE NODE},y,t} &= 0
\end{aligned}\right\} \quad \{\forall r, r1, y, t | (r, r1) \in \text{K}\}$$

3.1.3. Line losses

The line losses are calculated as a function of the line flow. This represents a piece-wise linear approximation to the quadratic loss function, adjusted as required to meet various circumstances.

$$Loss_{r,r1,y,t} = f(Stran_{r,r1,y,t}) \quad \{\forall r, r1, y, t | (r, r1) \in \text{K}\}$$

3.1.4. Node balance

According to Kirchoff's Second Law, the total line flows into and out of a node must equal the difference between the generation flowing into the node and the off-takes. Thus, the nodal balance constraints equate demand, generation, losses, electricity flows to/from the node. Generation deficit violation variables are also included in order to deal with those deficit situations in which the system may be unable to meet the load at a node, due to a

general shortage of generation, or to transmission system failure. The constraint below is written with the left hand side containing all sources of electricity at the node, and the right hand side containing all uses of electricity at the node.

$$\sum_{gf|(g,f) \in \Psi, g \in r} Gen_{g,f,y,t} + UnmetDem_{r,y,t} + \sum_{r1|(r,r1) \in K} Tran1_{r1,r,y,t} + \sum_{r1|(r,r1) \in K} Tran2_{r,r1,y,t} = Demand_{r,y,t} + \sum_{r1|(r,r1) \in K} Tran1_{r,r1,y,t} + \sum_{r1|(r,r1) \in K} Tran2_{r1,r,y,t} + \sum_{r1} Loss1_{r1,r,y,t} + \sum_{r1} Loss2_{r,r1,y,t} \{\forall r, y, t\}$$

Each line has a conventional direction associated with them. A positive *Tran1* variable represents power flowing into the node for some lines, and power flowing out for others. A fraction of the loss (LS) is attributed to the load end of the line. Demand is one of the key random parameters in the model. Given a distribution of peak and energy, the random sampling process draws a demand profile for each of the load block and the dispatch optimisation is repeated for each such demand sample (along with other random parameters).

In addition to these constraints, the model also includes other basic side constraints and balances including a capacity balance connecting the capacity additions over 2012–2017, seasonal energy limits for hydro power stations, capacity limits, minimum load for baseload power stations and maximum capacity factor for each power station. Finally, the model captures co-optimisation of energy and reserve as an integral part of the power flow optimisation. This is an important aspect in consideration of renewable energy as has been emphasised by Lamadrid and Mount [25] in their recent research. The following sub-section describes our formulation of the energy-reserve co-optimisation that directly represents contingencies associated with intermittent generation.

3.1.5. Reserve and contingency

The contingencies (or *Risk* variable in the model) are covered by holding reserve at a sub-set of generators. The model co-optimises reserve along with generation dispatch (*Gen*) from one or more fuels (*f*). *Reserve* needs to held at different generators to cover for system security events including intermittency in wind/solar. The following equations define the core of the dispatch/planning/pricing model:

- The aggregated intermittent generation (*Gen*) in each state is represented as the "risk generator" (*rg*) for each time block (*t*) in year (*y*), that is denoted as *Risk* for each reserve class (*rc*) as follows:

$$Risk_{rc,y,t} + Deficit\ Risk_{rc,y,t} \geq \sum_{rg,f} Gen_{rg,f,t,y} + \sum_{rg} Reserve_{rg,rc,y,t}$$

- Reserve requirement must be met by all other generators (*g*) some of which are running on multiple fuels (*f*). A constraint is placed on the provision of each class of reserve as a proportion (*ReserveProportion*) of the generator loading, limited by generation capacity (*Cap*), multiplied by overload factor (*OF*), as shown below:

$$\sum_{f} Gen_{g,f,t,y} + \sum_{rc} Reserve_{g,rc,y,t} \leq Cap_{g,y} \times OF_g$$

$$Reserve_{g,rc,y,t} \leq Reserve\ Proportion_{g,rc} \times \sum_{f} Gen_{g,f,t,y}$$

- Finally, reserve held at all generators must meet the *Risk* which in this case is created primarily by intermittent resources (that far exceed largest generator contingency).

$$\sum_{g} Reserve_{g,rc,y,t} \geq Risk_{rc,y,t}$$

The implication of the co-optimised reserve to cover for system risk requires a change in dispatch/price regime that system operators are known to follow. These ancillary services mechanisms are still not implemented in the Indian Power Exchanges although there are discussions underway to introduce ancillary services products in the Indian electricity market. If there is sufficient capacity in the system to cover for risk associated with loss of wind/solar, even then cheaper coal/gas/hydro generators may need to be backed off to hold reserve. This would affect dispatch and hence raise prices that would otherwise have resulted. High intermittency therefore would result in higher system costs and higher price volatility.

3.2. Key data and assumptions

The findings of the modelling analysis obviously depend on the data and assumptions used. There are two key sources of data for the technical data, namely:

1. The transmission network model is derived from a detailed power flow database from Central Electricity Authority (CEA) deployed by CEA to develop the National Transmission Plan [6] for 2016/17. The power flow database includes 3200 buses or nodes, 6874 transmission lines and transformers. We have used network reduction technique in Power System Simulator for Engineers (PSS/E) – a standard load flow analysis tool – to develop a reduced 33 zone model of the network corresponding to the States and Union Territories in India.
2. The existing generation system data is derived primarily from CEA's daily and monthly bulletins.[2] New generation expansion options and generation development scenarios including the Low Renewable and High Renewable (with gas) scenarios that we extensively discuss in later part of this paper, are also obtained from the CEA National Electricity (Generation) Plan (NEP).

We have overlaid the climate model data on top of the CEA/NEP generation data to represent the renewable generation constraints much more accurately than has been done in the NEP. As noted before, the NEP modelling treats all renewable projects as "must run" resource without considering their generation profile or economics in a highly simplistic manner. The main thesis of the present work is indeed to bring out the ramifications of ignoring the variability of renewable resources.

Other key assumptions for our study include:

- We have used real 2010/11 Indian Rupees (INR) and/or US Dollars (USD) using an exchange rate of 1 USD=INR 55 at the time of the study.
- Base year of 2016/17 which represents the end of the 12th Five Year Plan and CEA typically plans the system on a 5-yearly basis.
- Investment costs are taken from NEP (Generation) report.
- Plant characteristics including heat rate, hydro energy limits and operation and maintenance costs are collated from CEA monthly bulletins.
- Fuel prices for all existing and proposed plants are obtained from NEP.

[2] These bulletins are available online: http://cea.nic.in/welcome1.html.

- We have not considered the possibility of enhanced cross-border power trading [26] including the possibility of large-scale hydro power being imported from Bhutan and Nepal in future that can reduce the requirement of renewable power generation within the country.
- The peak and energy demand projections are sourced from the 18th Electric Power Survey [27] conducted by the Indian Ministry of Power and used in the NEP. We have used the median economic growth scenario under which the coincident peak demand in India is expected to exceed 230,000 MW by the end of the 12th Five Year Plan period. We have used the peak/energy projections from [27] in conjunction with load duration curve information provided in NEP [6, Chapter 13, p.229] to develop the forecast demand profile.
- Supply capacity also needs to keep pace with demand. In 2010/11, Indian power sector reported a total generation of just over 800 TWh consisting of
  - 665 TWh of thermal generation including coal/lignite generation of 583 TWh.
  - 114 TWh of hydro generation,
  - 26 TWh of nuclear, and
  - 6 TWh of import (from Bhutan).

In comparison, the 2016/17 energy requirement is expected to increase to 1391 TWh. Total generation capacity needs to grow from the 2010/11 level of 177 GW by approximately 100 GW. As noted above, we have used the generation expansion plan that formed part of a draft transmission planning dataset released by CEA for the specific purpose of this study. The additional capacity over and above existing capacity (in 2010/11) comprises primarily thermal accounting for 67 per cent of the addition followed by hydro (around 20 GW) and a relatively small share of nuclear plant. In 2016/17, there are more than 700 major generating units in the system that are modelled in NATGRID.

- It is envisaged that the increase in demand would generally be met through additional capacity. There is considerable uncertainty in both demand growth and generation addition as historic growth in generation and demand reveals. For instance, the annual generation growth over the last 4 years of the 11th Plan has varied between 2.7 per cent pa and 6.6 per cent pa. The projected uncertainty over the next 5 years can be approximated using a band around demand which is estimated based on historic supply/demand growth at a possible variation of ± 10 per cent around the projected demand that covers both demand growth and supply addition uncertainty.
- We have assumed a value of unserved energy of USD 500 MWh^{-1} which is relatively low by the international standard, but aligns with an estimated Rs 24.71 kWh^{-1} by Tata Energy Research Institute [28]. The value of USE estimate we have adopted is at the low end of the range of available estimates and to that extent, price volatility impacts that we have presented here should be seen as conservative.
- Other assumptions include:
  - Price of imported coal has been assumed to be in the range of USD 70–85 $tonne^{-1}$ as per the historic cost data reported by State and Independent Power Producers to the Ministry of Power and CEA;
  - random outage rate of generators by technology type that is derived from CEA statistics for power stations. This determines the probability for each generating unit to be on outage and is an input for the Monte Carlo simulation;
  - anticipated demand side management measures are already built into the peak/energy demand projections and no additional demand response has been considered in the analysis; and
  - availability of inter-state transmission capacity similarly is an input to Monte Carlo that is derived from transmission statistics for international utilities.

It is worthwhile to note that the results that are presented in the next section reflect the generally conservative nature of assumptions we have made on demand, supply and other parameters. For instance, we have used a median growth rather than high growth scenario and have assumed all of CEA's planned ~100 GW capacity will be delivered on time. We have also assumed a relatively low cost of unserved energy and coal prices both of which lead to a relatively low marginal cost estimates. On the other hand, a more flexible demand with significant customer demand response would offset some of the negative impacts of intermittent generation variability that has not been captured in the analysis.

3.3. *Key results*

3.3.1. *Base Case: comparison of high and low renewable scenarios*

We have simulated two NEP [6] scenarios, namely, LOW_RENEW (i.e., 18.5 GW additional renewable by 2017) and HIGH_RENW (i.e., 30 GW of additional renewable) scenarios, both of which also include 13 GW of new gas capacity additions. The National Electricity Plan refers to the LOW_RENEW scenario as the “Base” case, or most likely generation addition plan. The HIGH_RENEW scenario assumes 6000 MW less baseload capacity addition relative to LOW-RENEW. In other words, the total installed capacity of HIGH_RENEW is higher by 5500 MW, but it has less *firm* non-intermittent/conventional capacity.

Both these scenarios assume meeting a national annual energy requirement of 1371 TWh in 2016/17. The model results show that the annual cost of meeting this demand rises from 5.62 trillion INR in LOW_RENEW to 5.92 trillion INR in HIGH_RENEW – an increase of 5.3 per cent or INR 300 billion (approx. USD 5.5 billion). As Fig. 9 shows, the annual system cost increase may exceed INR 400 billion (approx. USD 7.3 billion or approximately 7 per cent) and will exceed INR 300 billion with a significant probability of 66 per cent. It will add on average INR 296 MWh^{-1} (or USD 5.4 MWh^{-1}) to the customer bill. An average residential customer in India typically pays INR 3000 MWh^{-1} and therefore the cost increase represents an increase of almost 10 per cent. While the cost implications at least in absolute terms is quite significant, we should bear in mind that this is a conservative estimate that assumes all planned generation and transmission capacity additions proceed for a median growth scenario, and unserved energy is valued at a modest USD 500 MWh^{-1}. As we have shown using a select set

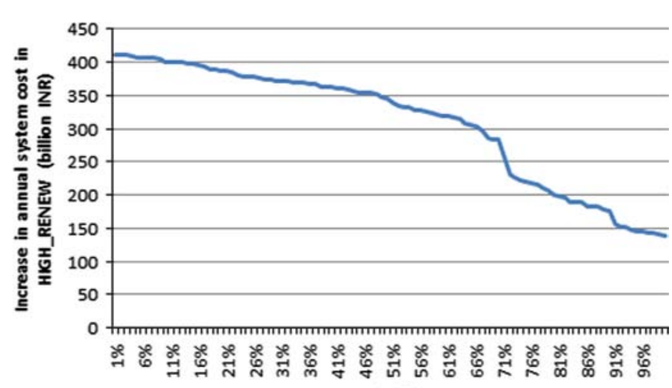


Fig. 9. Cumulative probability distribution of increase in system cost in HIGH_RENEW.

of sensitivities, the cost and unserved energy impacts can be much greater under more stringent conditions.

Nevertheless, it is clear that additional 11.5 GW of wind/solar included in the HIGH_RENEW scenario (relative to LOW_RENEW/Base) makes the system more prone to outages. The higher degree of intermittency also prevents some of the cheaper generation to be fully utilised due to an increased level of congestion on the network, and hence exposes the system to up to 7 per cent higher cost and potentially 10 per cent increase in energy bills to residential customers. The added costs arise from the significant swing in intermittent generation that has implications for congestion, increased peak/energy deficit, and changes in dispatch. It is remarkable that despite a significantly lower short run marginal cost of (additional 11.5 GW) renewable generation, the lower system reliability and congestion more than offset the fuel cost savings.

Fig. 10 shows the seasonal profile of wind and solar for LOW_RENW and HIGH_RENEW scenarios. These profiles show average dispatch outcomes across 100 samples each of which contains a co-optimised generation for wind/solar among all other generators in the Indian system. The resultant wind/solar generation profile also reflects the seasonal pattern we have observed in the underlying climate model results. Again, we observe that wind generation profile shows a sharp peak during the monsoon months (July/Aug), and it is particularly pronounced for the HIGH_RENEW scenario. This variability has major implications for system reliability and transmission congestion as we discuss below.

There are of course positive benefits of renewable in terms of reducing India's reliance on fossil fuel for power generation. An increase in wind/solar generation would not only impact on marginal oil/gas peaking stations, but would also reduce dispatch from coal-fired power stations, especially from marginal coal-fired power stations (i.e., those expensive and/or inefficient coal plants typically at the margin) during periods of surplus wind/solar generation. Fig. 11 shows output of Mettur Thermal Power Station (765 MW) in Tamil Nadu that reduces by 14 per cent on average. Since it is one of the more expensive coal plants in the region, it faces a more extreme prospect of being pushed down below 50 per cent capacity factor even for the LOW_RENEW scenario, depending on the demand growth and entry of other more efficient coal, gas and renewables. However, the HIGH_RENEW would render such a possibility more likely by taking away 600 GWh of mostly off-peak generation prospect. This is typical of several other coal-fired power stations in India under the HIGH_RENEW scenario. Reduction of coal-based generation, especially from older and inefficient stock of plants, is indeed a positive outcome. It however also raises an operational issue of managing the off-peak dispatch as some of the plants like Mettur would be forced to back down even below its minimum loading. In our simulations, Mettur has 12 per cent higher chance of being pushed below its minimum loading under HIGH_RENEW, relative to LOW_RENEW. It will increase wear and tear on these machines and in the longer term raises an issue of some of these power stations effectively being stranded investment. The collective dispatch variation also translates into highly variable flows on transmission lines including export/import from the states as we have discussed later in this section.

As the volume of intermittent generation availability fluctuates (both inter-annual and seasonal), there are periods of peak deficit in states like Tamil Nadu that will be heavily dependent on either local renewable generation, or import. Import may also be limited by transmission constraints. The net impact would be an increase in expected unserved energy (EUE) relative to a situation where there is a higher share of firm baseload capacity. Figs. 12–14 below discuss the expected unserved energy and transmission congestion implications.

Fig. 12 shows a comparison of EUE calculated using a Monte Carlo simulation across 100 samples of intermittent generation, generation/interconnection outage contingencies and load uncertainties. The average EUE is quite significant even for the LOW_RENEW at 81,500 GWh in 2017 (or approx. 6 per cent of the total national energy requirement). It however rises to 94,000 GWh for

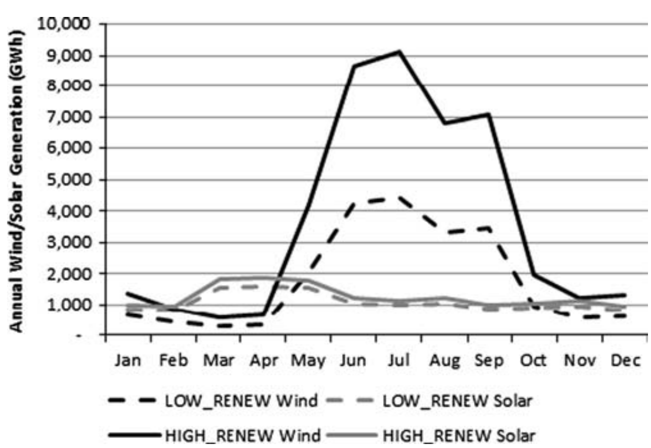


Fig. 10. Average wind/solar generation: seasonal profile.

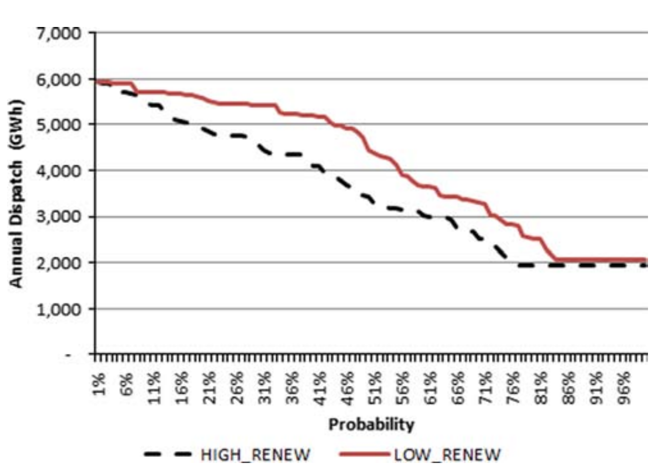


Fig. 11. Impact on annual dispatch of Mettur Thermal Power Station (Tamil Nadu).

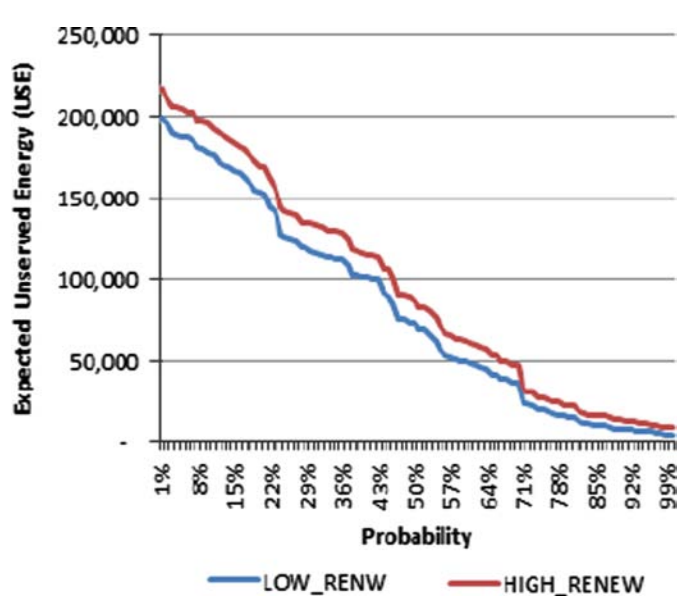


Fig. 12. Expected unserved energy (GWh): Low vs. High Renewable.

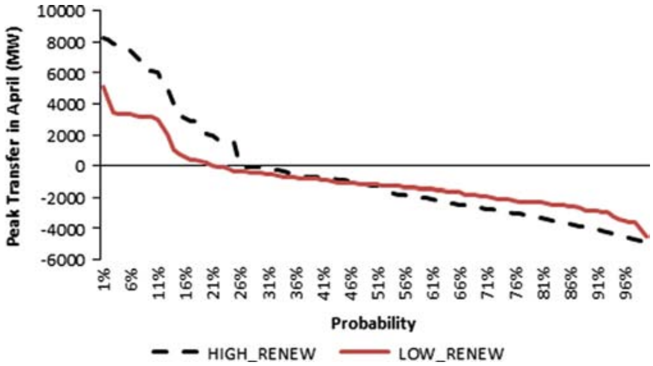


Fig. 13. Peak period transfer to (positive) or from (negative) Tamil Nadu in April.

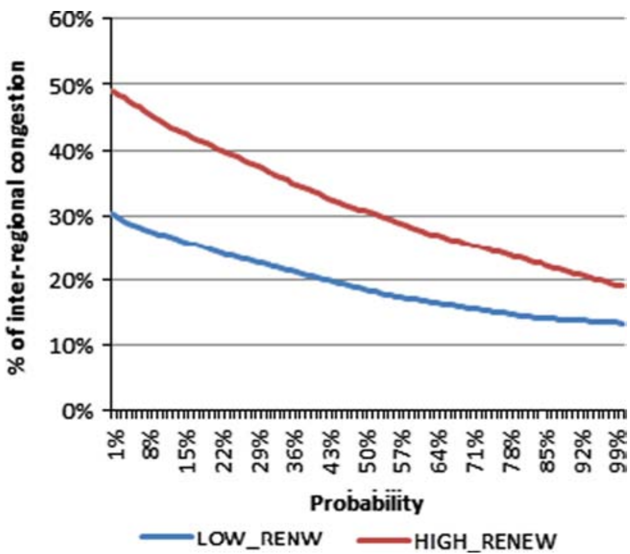


Fig. 14. Congestion (per cent time) on Southern–N.E.W. corridor.

the HIGH_RENEW scenario reflecting a 15 per cent increase when an additional 11,500 MW of wind/solar capacity is added to the system displacing 6000 MW of firm capacity. This is a reflection of the vulnerability of the system with high penetration of intermittent generation. The increase in EUE results from seasonal and inter-annual variability in wind and solar, as captured using the climate reanalysis data (shown in Figs. 5 and 6), coupled with inter-state transmission constraints.

As noted before, intermittency would add considerably to variability of transfers. Fig. 13 shows peak period transfers to/from Tamil Nadu in April across a range of random samples. Variation in demand across the samples renders some variability. However, high penetration of renewables can increase this variability quite significantly. Despite a significant increase in installed capacity in the HIGH_RENEW scenario, the state is overall more dependent on import. It also exposes its transmission system to considerably more stress with highly volatile flows.

A major ramification of increased intermittent generation penetration would be a sharp increase in congestion on critical transmission corridors. The Western to North–East–West (N.E.W. grid) corridor is congested on average 10 per cent of the time, if not less, in a year at present. Our simulations suggest that this will increase on average to 19 per cent of the time for LOW-RENEW and 32 per cent for the HIGH_RENEW scenario. Fig. 8 shows the cumulative probability distribution of Southern–N.E.W. corridor for 2017. Under HIGH_RENEW, excess off-peak wind, and the need for import during pre-monsoon months, can push the interconnectors to the limit for nearly 50 per cent of the time (i.e., over

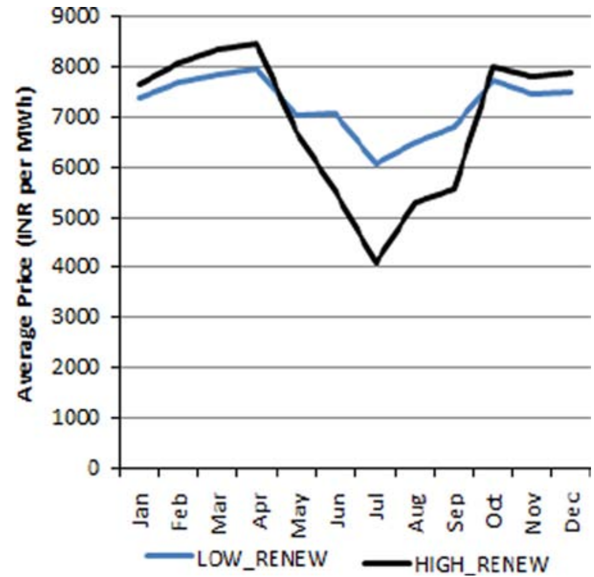


Fig. 15. System marginal cost (INR/MWh). Note: 1 US Dollar = INR 55.

4200 h) in a year. This obviously calls for a major enhancement of the inter-state/regional transmission capacity to evacuate renewable power, and also to boost import when wind generation drops in Southern Region.

Finally, Fig. 15 shows the average system marginal cost obtained from the model. Average marginal cost (across all samples and all states) shows a distinct peak during pre-monsoon (April/May) followed by a drop in prices during the monsoon period marked by excess wind generation. The HIGH_RENEW scenario shows a more prominent pre-monsoon peak and a sharper drop in prices due to significantly high volume of wind modelled. The sharp increase in Apr/May prices in Tamil Nadu has already been noted since 2009 [14]. What our present analysis reconfirms is that this trend will (a) become more pronounced; and (b) become a feature throughout India, as the volume of intermittent generation grows. The *average* prices, however, do not reveal clearly that there are considerable numbers of very high price spikes in the region of INR 15,000–20,000 (USD 272–336) MWh^{-1}. While price volatility is an essential part of an electricity market, we note that in this case the future volatility is induced by somewhat artificial policy driven introduction of high volume of intermittent generation.

3.3.2. *Sensitivity cases: comparison of high and low renewable scenarios*

In order to show the impact of variation in key parameters, we have constructed three sensitivity cases, namely:

1. *Higher demand*: Peak demand in 2016/17 is 10 per cent higher and energy requirement is 7 per cent higher. Such an increase in well within the realm of possibilities that has been outlined in the higher demand growth scenarios in the 18th Electric Power Survey as well as other forecasts, e.g., [29]. We have also retained the same band of uncertainty as in the Base Case for Monte Carlo simulations to capture potential variability in peak/energy growth over the years;
2. *Higher demand and VoLL*: In addition to higher peak/energy, we also raise VoLL to USD 1000 MWh^{-1} that brings it more in line with the value of unserved energy (or value of customer reliability) used in other developing nations, albeit, it still remains well below the level used in developed nations [30]; and

Table 2
Comparison of HIGH_RENEW and LOW_RENEW scenarios: difference in system costs and unserved energy.

Scenario	System Cost Increase (INR/USD)	Expected Unserved Energy Increase (TWh)
Base Case	INR 300b (or USD 5.5b)	12.50
Higher demand	INR 544b (or USD 9.9b)	21.75
Higher demand and VoLL	INR 979b (or USD 17.8b)	21.54
Higher demand, VoLL and coal price	INR 1032b (USD 18.8b)	22.13

3. *Higher demand, VoLL and coal price*: Finally, we also add to sensitivity (2) above, a 20 per cent increase in coal price to reflect an increase in domestic price that has taken place in January 2011 and May 2013 [31], and also increasing reliance on imported coal.

We are specifically interested to see how some of these downside risks impact on the HIGH_RENEW cost and unserved energy outcomes, relative to their LOW_RENEW counterpart. In other words, we are interested to see if the addition of 11,250 MW (at the expense of 6000 MW of baseload capacity) makes the system more vulnerable/expensive under more stressed demand scenarios. Cost/USE outcomes for the sensitivity cases are presented in Table 2.

The results demonstrate:

- *Higher Demand*: The cost impact increases substantially from INR 300 billion (USD 5.5 billion) to INR 544 billion (USD 9.9 billion) if the 2017 peak/energy requirement is higher. As the 1371 TWh demand in the Base Case itself is an onerous requirement that leaves 12.50 TWh of unserved energy, a further 7 per cent increase in energy, or 95.97 TWh leads to an increased unserved energy level of 21.75 TWh. The increase in unserved energy primarily explains the increase in system cost, albeit there are other minor factors such as a decrease in fuel costs and losses as part of the demand in HIGH_RENEW (relative to LOW_RENEW) is not being met.
- *Higher demand and VoLL*: If we also consider a higher opportunity cost of power outage at USD 1000/MWh (rather than USD 500/MWh) under the higher demand scenario, the system cost impact is nearly double, although the expected unserved energy remains almost the same suggesting that vast majority of the supply options are already exhausted in the Base Case. However, there are very expensive peaking capacity with very limited utilisation potential, that would not be considered for an economic opportunity cost of USD 500/MWh, are selected in this case which marginally reduces expected unserved energy. This sensitivity shows that the cost to the Indian economy under a high demand growth scenario with a higher opportunity cost of following an overly aggressive intermittent renewable development may be as high as USD 17.8 billion year^{-1}.
- *Higher demand, VoLL and coal price*: Finally, if we also superimpose a higher cost of coal, it would discourage some of the investment in new coal for both LOW_RENEW and HIGH_RENEW. As the baseload capacity is further diminished, it increases unserved energy, albeit not very significantly over and above the “Higher demand, VoLL” scenario. This is because the LOW-RENEW scenario that considers a higher portfolio of new coal is affected more, and hence the *difference* in unserved energy with HIGH-RENEW remains does not increase significantly.
- In summary, the sensitivity results show that if we consider a less conservative scenario with higher demand, coal price and opportunity cost of electricity – the cost to the economy associated with a HIGH_RENEW scenario can more than triple to over a trillion INR (or USD 18.8 billion) *per year*, relative to the Base Case.

4. Summary and concluding remarks

Renewable energy development in India has progressed at a rapid pace, especially from 2010. It is envisaged to maintain a strong growth over the next decade, fuelled by several policy initiatives. It is a significant issue that holds the key to reducing India's reliance on coal. However, every major development including that of renewable power must be critically assessed to ensure the growth is sustainable from all perspectives including the economics and security of the power system. Since large-scale penetration of intermittent renewable resources is still a relatively new phenomenon in India, the power system planning bodies must take special care considering it is still a peak-deficient system that also needs baseload capacity. In fact, if we look at Tamil Nadu in Southern India that has already seen more than 7000 MW of wind, and very little baseload power development in recent years, it is clear that an excess of intermittent generation is already taking its toll in terms of large seasonal peak/energy deficits, extreme volatility in prices and heavy stress on the transmission system. We believe better planning needs to be done using climate model data that is already available to shape where, how much and when new renewable capacity should be added to augment other forms of capacity, without compromising economics or security.

We have used climate modelling reanalysis data over the past 20 years from the CSIRO CCAM model to develop a probability distribution of both wind and solar for all relevant Indian states. We have then used these distributions in an electricity planning and operation optimisation model that is capable of capturing uncertainties on demand, fuel costs as well as those around seasonal and temporal distribution of wind/solar. Further, the model explicitly captures the contingencies associated with intermittent wind/solar generation using the latter distribution.

Our analysis for the Indian power system for 2017 uses a Low (18,500 MW of renewable) and High (30,000 MW of renewable) Renewable scenarios. These scenarios are derived directly the latest *National Electricity Plan* prepared by the Central Electricity Authority of India [6]. We have compared and contrasted the Low and High Renewable scenarios to conclude that,

- Notwithstanding the negligible operating cost of renewable projects, their intermittent nature increases expected system costs by 5.3 per cent or USD 5.5 billion year^{-1} in the High Renewable scenario, relative to the Low Renewable counterpart, even for a reasonably conservative set of assumptions around demand growth, cost of unserved energy and fuel price;
- The additional costs in part reflect the fact that the High Renewable scenario exposes the system to a higher risk of outage absent adequate baseload capacity. More precisely, the expected unserved energy in this scenario is 12,500 GWh, or 15 per cent higher compared to the Low Renewable scenario, despite the system having 5500 MW of additional installed capacity, but less *firm* (baseload) capacity. This outcome highlights that the high degree of seasonal variability in wind and solar especially during the pre-monsoon months of April and May need firm capacity to augment renewables;
- The sensitivity results show that if we consider a less conservative scenario with higher demand, coal price and opportunity cost of

electricity – the cost to the economy associated with a High Renewable scenario can more than triple to over a trillion INR (or USD 18.8 billion) *per year*, relative to the Base Case.

- There is already a marked trend of price volatility in Southern India during April and May arising from this seasonal trend in wind as the market prices from Indian Energy Exchange amply demonstrates. Our analysis also conclude that by 2017, this volatility will go up considerably with very sharp peaks in prices during April/May followed by low prices during months of excess wind. Pre-monsoon monthly average prices will be close to INR 8400 MWh^{-1} (or in excess of USD 150 MWh^{-1}) and drop to INR 4000 MWh^{-1}, i.e., less than half of it, during July.
- The seasonal and temporal intermittency will also exert significantly higher pressure on the transmission system. Some of the high wind/solar states like Tamil Nadu would experience very high swings in its import/export requirement. Overall congestion on the Southern and rest of the Indian power system corridor is fairly manageable at less than 10 per cent today. It will nearly double even for the Low Renewable scenario and more than treble for the High Renewable scenario.
- Therefore, the location, volume and timing of renewable projects need a better scrutiny to ensure that these negative impacts are minimised by selecting appropriate generation and transmission resources. There is a need for a more balanced approach to ensure that selection of renewable projects do not add to system cost, price volatility and unserved energy. Indeed, we have also shown that wind/solar contributes to reduction of generation from old and inefficient coal-fired power stations, which is one of the major reasons for introducing renewables. However, it is also important that these disbenefits are weighed against the emissions reduction benefits to adopt a more holistic approach to ensure a more balanced growth of the Indian power system.
- A balanced addition of renewable energy needs to consider both the mix of renewable and non-renewable, as well as the mix *across* different types of renewable energy. Specifically, the location and ratio of solar, wind and baseload biomass capacity can be selected judiciously to improve supply reliability *and* system economics. If the generation and network planning properly recognise the ill-effects of intermittency and select sites/resources in a way that negate the relative impact of intermittency across solar and wind in different zones, and also augment with non-intermittent renewables (such as biomass in North-Eastern states of India where neither solar or wind potential is good), a good mix of renewable resources can maintain an acceptable grid stability if not enhance it while improving the system economics. Climate modelling data that we have discussed in this paper can be useful in determining such a mix. It is envisaged that future work in this area will look into these issues.

In conclusion, the analysis presented here reinforces some of our earlier observations [3,14] that any zeal for rapidly increasing renewable penetration must be tempered with scientific analysis. It is important to understand the true benefits *and costs* associated with wind and solar. The high seasonal variability and correlation for renewable-rich states poses a problem, not to mention low resource intensity in other states where renewable investment should never be encouraged. The ramifications are particularly grave in a system that is already peak and energy deficit, as these investments are virtually foreclosing other conventional generation development including baseload projects. Power system planning should embrace results from climate models to analyse a range of operation, investment and policy questions related to renewable energy integration. Our analysis shows the potential for an integrated climate-power modelling analysis in the Indian context to highlight significant challenges that wind/solar intermittency is likely to present in the near future, including the need for further work to develop a balanced mix of renewable resources.

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